Mitigating hydrate formation in onshore gas wells: A case study on optimization techniques and prevention

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MITIGATING HYDRATE FORMATION IN ONSHORE GAS WELLS: A CASE STUDY ON OPTIMIZATION TECHNIQUES AND PREVENTION

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Abstract:

Gas wells, particularly those situated onshore, play a vital role in the global energy sector by supplying a significant portion of natural gas. However, operational challenges, notably gas hydrate formation, pose substantial issues, leading to complications such as flowline blockages and unexpected well shutdowns. Gas hydrates, crystalline structures resembling ice, form under specific conditions of low temperature and high pressure. This paper explores the complex process of hydrate formation in gas wells, emphasizing the challenges it presents and the need for specialized strategies to address these issues.

The primary focus is a case study of an onshore gas well experiencing recurrent hydrate-related problems. Leveraging PipeSim software, a well model is developed, followed by a sensitivity analysis under various operational scenarios. The study investigates mitigation strategies, including choke position adjustments and methanol introduction, crucial for the safe production of oil and gas fields.

The significance of this study lies in its aim to optimize well performance and mitigate risks associated with hydrate formation. Findings contribute to existing knowledge and offer practical solutions for industry practitioners and researchers dealing with onshore gas wells. The paper's structure includes a review of related work, details on the experimental setup and results, and concluding remarks.

The perennial challenge of hydrate formation in gas wells necessitates a case-specific assessment and individualized approaches. Nodal analysis and well modeling software have become indispensable tools for engineers in developing preventative measures. This paper presents a methodological approach using a specific well as an example, evaluating the effectiveness of three methodologies: downhole choke installation, methanol dosing, and well transfer to a high-pressure separator.

Keywords: Gas Well, Gas Hydrate Formation, Well Modeling, Well Performance Optimization, Choke Position Adjustments, Methanol Injection

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1 INTRODUCTION

Gas wells, especially those located onshore, are integral components in the global energy sector, providing a substantial source of natural gas. These wells, however, are susceptible to various operational challenges, with gas hydrate formation being a predominant issue (“Gas Hydrate Control,” 2015; Makagon 1997). Gas hydrates are crystalline ice-like structures that form under specific conditions of low temperature and high pressure, often leading to complications such as blockages in the flowlines and unexpected well shutdowns.

The formation of hydrates in gas wells is a complex process that occurs under specific conditions of high pressure and low temperature. When natural gas, which contains methane, ethane, propane, and other similar components, flows through a gas well, these gases have the potential to physically combine with water molecules present in the fluid. Under the influence of high pressure, a hydrate crystal lattice is formed, capturing gas molecules within its structure. This process results in the formation of solid hydrates that can accumulate in wells. It is important to note that the presence of certain conditions, such as low temperatures and enough water, is crucial for the formation of hydrates in gas wells. The absence of any of these conditions prevents their occurrence. This phenomenon can pose significant challenges in the exploitation of gas resources, necessitating the development and implementation of specialized strategies to avoid potential operational difficulties caused by the presence of hydrates. (Sloan, 2010; Straume et al., 2016).

The primary objective of this paper is to present a comprehensive case study of an onshore gas well that has been experiencing recurrent issues related to hydrate formation. Through the utilization of PipeSim software, a base model of the well was meticulously developed. This was followed by a sensitivity analysis focusing on hydrate formation under various operational scenarios. The study further explores and analyzes different mitigation strategies, including the adjustment of choke positions and the introduction of methanol. Understanding and predicting gas hydrate formation is crucial for the safe production of oil and gas fields (Duan et al., 2023).

This study is significant as it aims to optimize the well's performance and mitigate the risks associated with hydrate formation. The findings of this study will not only contribute to the existing body of knowledge but will also provide valuable insights and practical solutions for industry practitioners and researchers dealing with onshore gas wells.

The remainder of the paper is structured as follows. Section 2 highlights related work. The experimental setup and its results from real-world applications are detailed in sections 3 and 4, respectively. Finally, conclusions are presented in section 5.

2 RELATED WORK

Musakaev and Borodin (2021) conducted mathematical modeling of gas hydrate formation in a zonal heterogeneous porous reservoir. Their work provides insights into the process of gas hydrate formation in different zones of a reservoir, which is crucial for understanding and predicting hydrate-related issues in onshore gas wells.

A study by Wang et al. focused on hydrate formation during the intervention operations of deepwater high temperature and pressure gas wells. Although their study is based on deepwater wells, the established temperature-pressure coupling model and the physical simulation experiment of hydrate formation provide valuable insights that can be applied to onshore gas wells under specific conditions. Shukla, Singha, and Sain (2022) worked on modeling in-situ horizontal stresses and orientation of maximum horizontal stress in gas hydrate-bearing sediments in the Mahanadi offshore basin in India. While their study is based on offshore basins, the modeling techniques and findings can be insightful for understanding stress orientations in onshore gas hydrate-bearing sediments.

Hashemi et al. (2019) conducted an experimental study and modeling of the kinetics of gas hydrate formation for various hydrocarbons in the presence and absence of SDS. Their work provides valuable data and insights into the kinetics of hydrate formation, which is crucial for developing effective hydrate management strategies in onshore gas wells. The formation of gas hydrates in onshore gas wells is a significant operational challenge, necessitating effective management strategies (Song et al., 2020). Song et al. conducted a study focusing on deepwater gas well testing operations in the South China Sea, providing valuable insights into hydrate management strategies. The study explored three strategies: thermodynamic hydrate inhibitor (THI) injection, hydrate slurry flow technology, and kinetic hydrate inhibitor (KHI) injection. Each strategy presents unique advantages and challenges that are crucial for industrial applications.

Nwankwo (2019) presented a case study of an onshore gas well that was crucial for fueling a flow station. The well experienced frequent shutdowns, not due to equipment failures but because of the Joule-Thompson effect. Through the development of a temperature-sensitive production performance model, the study found that immediate chemical hydrate inhibition was not necessary. Adjusting the choke size to increase flow line pressure allowed the well to operate in a non-hydrate formation region, ensuring stable production.

A recent study by Ping et al. (2022) focused on evaluating the risk of gas hydrate formation in ESP-Lifted Natural Gas Hydrate Wells. The study established a gas-liquid two-phase flow model to predict the hydrate formation region in dedicated gas/water lines and mixing-delivery lines. The research provided insights into the influence of the operating frequency of Electric Submersible Pumps (ESP) and the power of heaters on temperature and pressure in the wellbore, contributing to the understanding and mitigation of the risk of secondary hydrate formation in ESP-lifted wells.

Wei, Jiang, Zhao, Zhou, Zhang, Li, Sun, and Li (2021) present a theoretical model for the non-equilibrium formation and decomposition of hydrates in marine gas/water-producing wells. The model is based on a phase equilibrium model of methane hydrate and a kinetic model of hydrate formation and decomposition. The authors also develop a wellbore temperature and pressure distribution model for water-bearing natural gas recovery. Numerical simulations are used to verify the accuracy of the theoretical model and to study the factors that affect hydrate formation and decomposition.

3 METHODOLOGY

The methodological framework employed in this study comprises four key steps, each meticulously designed to ensure a robust and systematic approach to our research objectives. The following sections outline the sequential stages of our methodology: Data Collection, Creating and Matching the Model, Performing Sensitivity Analysis, and Finalizing Results. Each step is integral to the comprehensive understanding and interpretation of the data, contributing to the reliability and validity of our findings. The schematic representation below (Figure 1) illustrates the interconnected nature of these methodological components, emphasizing the seamless flow from data collection to the conclusive interpretation of results.

Figure 1 Schematic representation of methodology

3.1 Data Collection

Data for this study were sourced directly from an operational onshore gas well experiencing issues with hydrate formation. The dataset encompasses various parameters crucial for the analysis, including pressures and flow rates (Table 1) and gas composition (Table 2). In Table 3, the results of relevant hydrodynamic measurements are presented, more precisely, measurements of dynamic pressure stages in the wellbore and pressure gradient. The current equipment at the well is described in Table 5, where information about the production downhole equipment is listed, while Table 6 presents information about the surface equipment. Prior to analysis, the dataset underwent rigorous cleaning and pre-processing to eliminate any outliers or missing values, ensuring the accuracy and reliability of the data used in the study.

Table 1 Input data

Parameter	Pres [bar]	Pbh [bar]	Pwh [bar]	Psep [bar]	Qg [m^3/day]	Qf [m/day]
Input data	90.4	87	65	7.3	9191	0.1
Model results	91	86.8	65	7.3	9115	0.099

Table 2 PVT data

Serial number	Components	Unit of measure	Value
1.	Methane	mol %	95.30
2.	Ethane	mol %	0.26
3.	Propane	mol %	0.06
4.	Isobutane	mol %	0.00
5.	Butane	mol %	0.02
6.	Isopentane	mol %	0.00
7.	Pentane	mol %	0.00
8.	Hexane	mol %	0.09
9.	Nitrogen	mol %	3.45
10.	Carbon Dioxide	mol %	0.82
11.	Average molecular weight	g/mol	16.81
12.	Density relative to air	/	0.5813
13.	Density	kg/m^3	0.7123
14.	Wobbe's index (bottom)	MJ/m^3	43.02
15.	Lower heating value	MJ/m^3	32.80

Table 3 HD measurements

Depth	PRESSURE (kPa) – LEVEL (m)	
	Staircase	Dynamic
m	Dynamic	Grad.
3	kPa	kPa/m
0	6518	
100	6730	2,12
200	6980	2,50
300	7249	2,69
400	7495	2,46
500	7748	2,53
600	7967	2,19
700	8193	2,26
750	8316	2,46
800	8430	2,28
865	8588	2,43

Table 4 Data on production equipment

	Data on production equipment			
1	Inside diameter of column	127,3	*[mm]*	
2	Column outer diameter	139,7	*[mm]*	
3	Column section length	1239,5	*[m]*	
4	Column grade	H-40		
5	Tubing inner diameter	50,7	*[mm]*	
6	Tubing outer diameter	60,3	*[mm]*	
7	Tubing section length	858,7	*[m]*	
8	Tubing grade	J-55		
9	Packer installation depth	859,98	*[m]*	
10	Special equipment (description, characteristics, installation depth)	✓		
11	Perforation top	925	*[m]*	
12	Perforated interval length	1,5	*[m]*	
13	Inclinometer data	✓		
14	Geothermal gradient	X	[°C/m]	Not necessary, preferred

Table 5 Surface equipment data

Data on surface equipment				
1	Pipeline length	420	*[m]*	
2	Internal diameter of the pipeline	73	*[mm]*	
3	Pipe wall thickness	5,2	*[mm]*	
4	Coefficient of thermal conductivity of pipelines	X	*[W/mK]*	
5	Absolute roughness of the inner wall of the pipeline	X	*[mm]*	
6	Average digging depth	0,8 - 1 m	*[m]*	
7	Soil temperature at the depth of burial	X	*[°C]*	
8	Thermal conductivity coefficient of the soil	X	*[W/mK]*	
9	Thermal conductivity coefficient of polyurethane foam insulation	X	*[W/mK]*	
10	Separator pressure	44	*[kPa]*	the well works through high pressure
11	Separator temperature	X	*[°C]*	

3.2 Creating and matching the model

NODAL analysis, as utilized in this study to model the well's performance (Mach et al. 1979), is a crucial technique in the realm of oil and gas reservoir engineering. It can be described as a systematic and comprehensive approach to assessing and optimizing the functionality of oil and gas wells, spanning from the reservoir to the wellhead. This analytical method considers various parameters such as wellbore configuration, tubing size, casing, and completion details, faithfully representing the intricacies of the actual well conditions.

The application of nodal analysis as the primary methodology in this study attests to its efficacy in understanding and predicting well behavior. By employing nodal analysis, researchers can identify and analyze the myriad factors that influence well performance, offering valuable insights into how the well is expected to behave under diverse scenarios. This method provides a holistic perspective on the entire well system, allowing for precise predictions and targeted optimizations to enhance overall performance.

In the context of the oil and gas industry, IPR (Inflow Performance Relationship) and VLP (Vertical Lift Performance) are crucial concepts in the analysis of well performance. IPR represents the relationship between the production rate of a well and the flowing bottomhole pressure. Understanding IPR is essential for optimizing production and managing reservoir performance. On the other hand, VLP is concerned with the relationship between the production rate and the tubing head pressure, focusing on the efficiency of artificial lift systems (Golan & Whitson, 1991).

The formulation used to describe surface liquid production rates and wellbore flowing pressure is referred to as the Inflow Performance Relationship (IPR). This concept has been extensively employed since the advent of bottom hole gauges in the 1920s. The simplest equation within the IPR framework is the Productivity Index. This index signifies the ratio of the total liquid surface flowrate to the pressure drawdown at the midpoint of the producing intervals and is expressed in Equation 1 (Golan & Whitson, 1991).

$$J = \frac{Q}{Pr - Pwf} \tag{1}$$

Where:

J – Productivity index, $m^3/d/bar$

Q- Surface flowrate at standard conditions, m^3/d

Pr – Static bottom hole pressure, bar

Pwf – Flowing bottom hole pressure, bar

From Eq. 2 surface flowrate at standard conditions is defined as:

$$Q = J\,(Pr - Pwf) \tag{2}$$

In a great number of mature wells there are no downhole pressure gauges installed and flowing bottom hole pressure can be estimated from Eq. 3 (Boxer, 1988).

$$Pwf = Pc + \left(\frac{\rho \cdot g \cdot H}{1000}\right) \tag{3}$$

Where:

Pc – Casing pressure, bar

ρ – Density of liquid, kg/m^3

g – Acceleration of gravity, value 9,81 m/s^2

H – Height of fluid column, m

Vogel gives the second available method in Eq. 4 (Vogel, 1968).

$$Q = Q_b + (Q_{max} - Q_b)(1 - 0.2\frac{Pwf}{Pb} - 0.8\frac{P_{wf}^2}{P_b^2}) \tag{4}$$

Where:

Q – Production rate, m^3/d

Pb – Bubble point pressure, bar

Qmax – Maximum vogel rate, m^3/d

Qb – Measured rate at bubble point, m^3/d

Maximum Vogel rate is given in Eq. 5.

$$Q_{max} = \frac{P_b \cdot J}{1.8} \tag{5}$$

And in Eq. 6 is given rate measured at bubble point.

$$Q_b = J(P_r - P_b) \tag{6}$$

Therefore, the productivity index by Vogel is given in Eq. 7.

$$J = \left(\frac{Q}{(Pr - Pb) + \frac{Pb\,(1 - 0.2\frac{P_{wf}}{P_b} - 0.8\frac{P_{wf}^2}{P_b^2})}{1.8}} \right) \tag{7}$$

The relation indicates that for each pressure decreasing on the bottom of drawdown or relief of formation backpressure against the face of the formation, result will be increase in production rate. Casing pressure have significant effect on production rate (Martinovic, 2022).

Vertical Lift Performance (VLP) correlations are empirical relationships or mathematical expressions that help predict and analyze the performance of artificial lift systems in oil and gas wells. These correlations are essential tools for engineers and practitioners in the industry to estimate production rates, optimize lift systems, and make informed decisions about well operations.

The Gray Vertical Flow correlation, developed by H. E. Gray from Shell Oil Company, is employed to analyze pressure loss and holdup in vertical gas and condensate systems, where the predominant phase is gas. This correlation treats the flow as single-phase, assuming that any separated water or condensate adheres to the pipe wall. The applicability of this correlation is observed in vertical flow scenarios characterized by velocities below 15.24 m/s., tube sizes below 88.9mm, condensate ratios below 225 m^3/d, and water ratios below 8 m^3/d (Pipesim, 2017).

The creation of a well model during NODAL analyses consists of the following steps:

1. Input Well completion details: Enter completion details such as tubing size, casing size, completion type, and any artificial lift methods if applicable.
2. PVT Properties: Define the PVT properties for the well fluids. Input information such as fluid composition, density, viscosity, and other relevant properties. This data is crucial for accurate fluid flow calculations.
3. Define Well Inflow Performance Relationship (IPR): Establish the relationship between wellbore pressure and production rate. This is crucial for predicting well productivity under various conditions.
4. Definition of Hydrodynamic Measurements: Data from the results of the last relevant measurements of dynamic pressure profiles in the well are entered.
5. Vertical Lift Performance (VLP): Set up Vertical Lift Performance (VLP) models, that involve defining the well's response to changes in tubing and casing pressures.
6. Run Nodal Analysis: Execute the nodal analysis to simulate the well's behavior under the specified conditions. PipeSim will calculate pressures, temperatures, and flow rates at different points in the well and production system.
7. Review Results: Analyze the simulation results, focusing on parameters such as wellhead pressure, tubing and casing pressures, flow rates, and temperature profiles. Evaluate the well's performance under different operating conditions.
8. Optimization: If necessary, adjust parameters such as choke size, completion design, or artificial lift settings to optimize well performance.

3.3 Sensitivity Analysis

A sensitivity analysis was conducted post the development and validation of the well model. This analysis aimed to examine the impact of various operational parameters on hydrate formation, focusing specifically on choke positions, methanol injection rates and separator pressure.

The main goal of these analyses is to find the optimal solution for preventing hydrate formation and ensuring stable production. Additionally, this type of analysis allows us to compare different approaches to addressing the issue and evaluate their impact on well behavior.

Choke Position Analysis: Different choke positions were simulated, and their impact on the well's pressure and temperature profiles were analyzed. These profiles are crucial in understanding the conditions under which hydrates form. By changing the choke position, a sudden drop in pressure is facilitated under different temperature conditions, reducing the likelihood of hydrate formation. By varying the choke depth from the wellhead towards the bottom, every 50 meters, the shallowest installation point will be determined to ensure stable operation.

Methanol Injection Analysis: The study also simulated various rates of methanol injection to evaluate their effectiveness in preventing hydrate formation. Methanol, serving as a thermodynamic inhibitor, lowers the temperature at which hydrates form, mitigating the risk associated with their formation. The main goal of the analysis is to determine the exact position for injecting hydrate inhibitors and to identify the minimum quantity of chemical required to prevent hydrate formation, aiming to optimize operational production costs. The precise injection point will be determined through the analysis of hydrate formation risk graphs, and the injection point will be placed immediately before the hydrate formation risk zone. Following that, by varying the daily amount of injected methanol, the minimum sufficient quantity will be determined.

Changing the separator pressure: One of the methods to prevent hydrate formation is changing the separator pressure. This involves transferring the well from a low-pressure separator to a high-pressure separator, provided that the aboveground infrastructure allows for it. In the case of this well, the transfer from a separator pressure of 5 bars to a separator pressure of 43 bars will be analyzed. Such a change reduces the pressure drop across the choke, decreasing the likelihood of hydrate formation.

4 RESULTS AND DISCUSSION

Based on the analysis of the production profile, it can be concluded that the well casing is hermetic, and the well produces a very small quantity of fluid, approximately 0.1 m^3/d. During the monitored period, there were two choke size changes, from 3 mm to 3.3 mm at the end of June and from 3.3 mm to 3.5 mm in mid-July, both accompanied by an increase in production. Between November 25th and December 15th, a sudden tubing pressure spike was observed, coinciding with a production decline. As there was no corresponding increase in line pressure and considering external temperatures during that time of the year, it is concluded that hydrate deposits are forming. Production stabilizes after pipeline cleaning. Subsequent regular methanol dosing prevents the formation of significant deposits and production decline. In September, the well is switched from a low-pressure separator to a high-pressure separator, leading to a reduction in choke pressure drop and a decreased likelihood of hydrate formation.

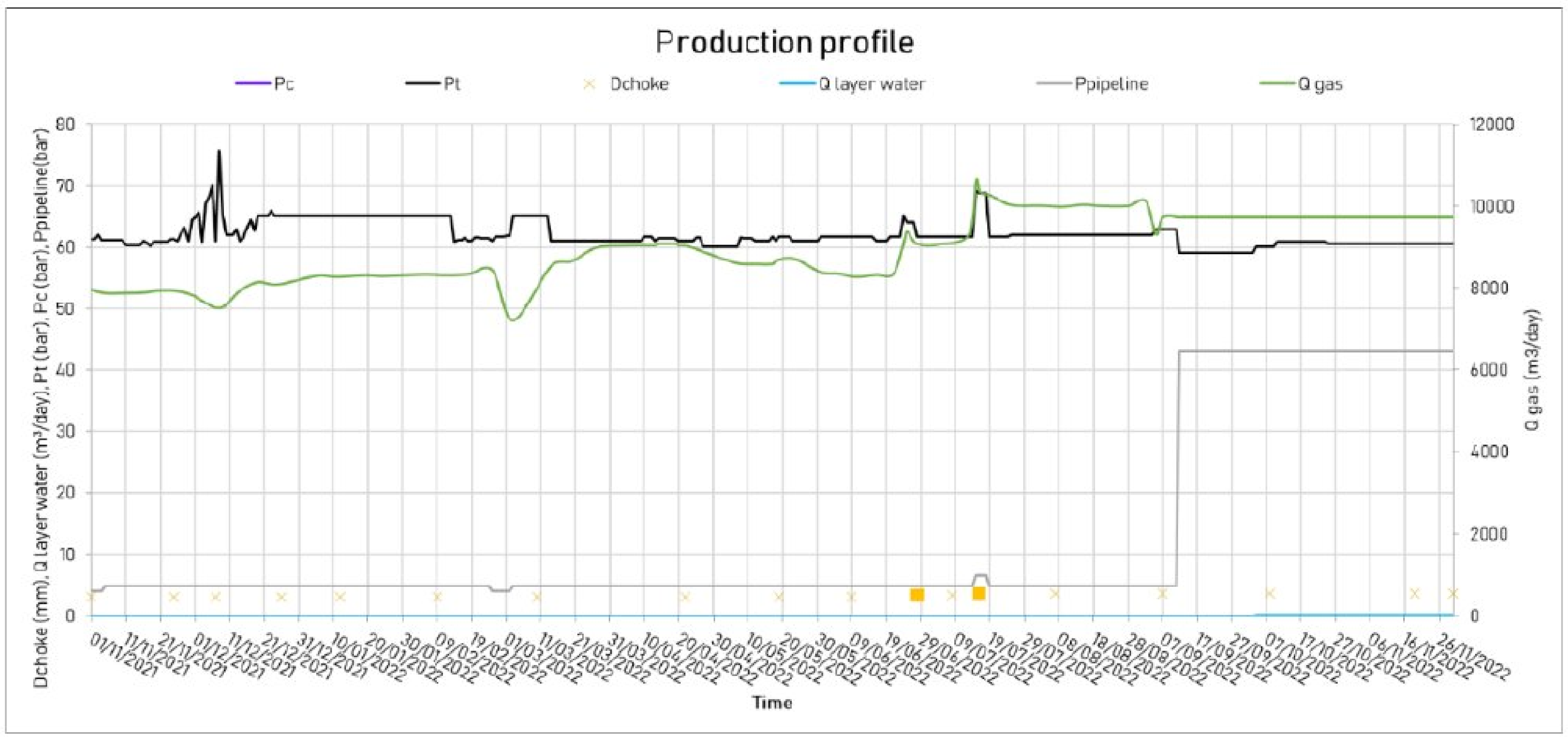

Figure 1 Production profile

In Figure 2, a wellbore sketch generated in Pipesim is presented based on the downhole production equipment data from Table 4. Additionally, the nodal point at the bottom of the well at a depth of 912 m is depicted in the figure. Figure 3 illustrates the surface infrastructure and the position of the upper nodal point located at the wellhead.

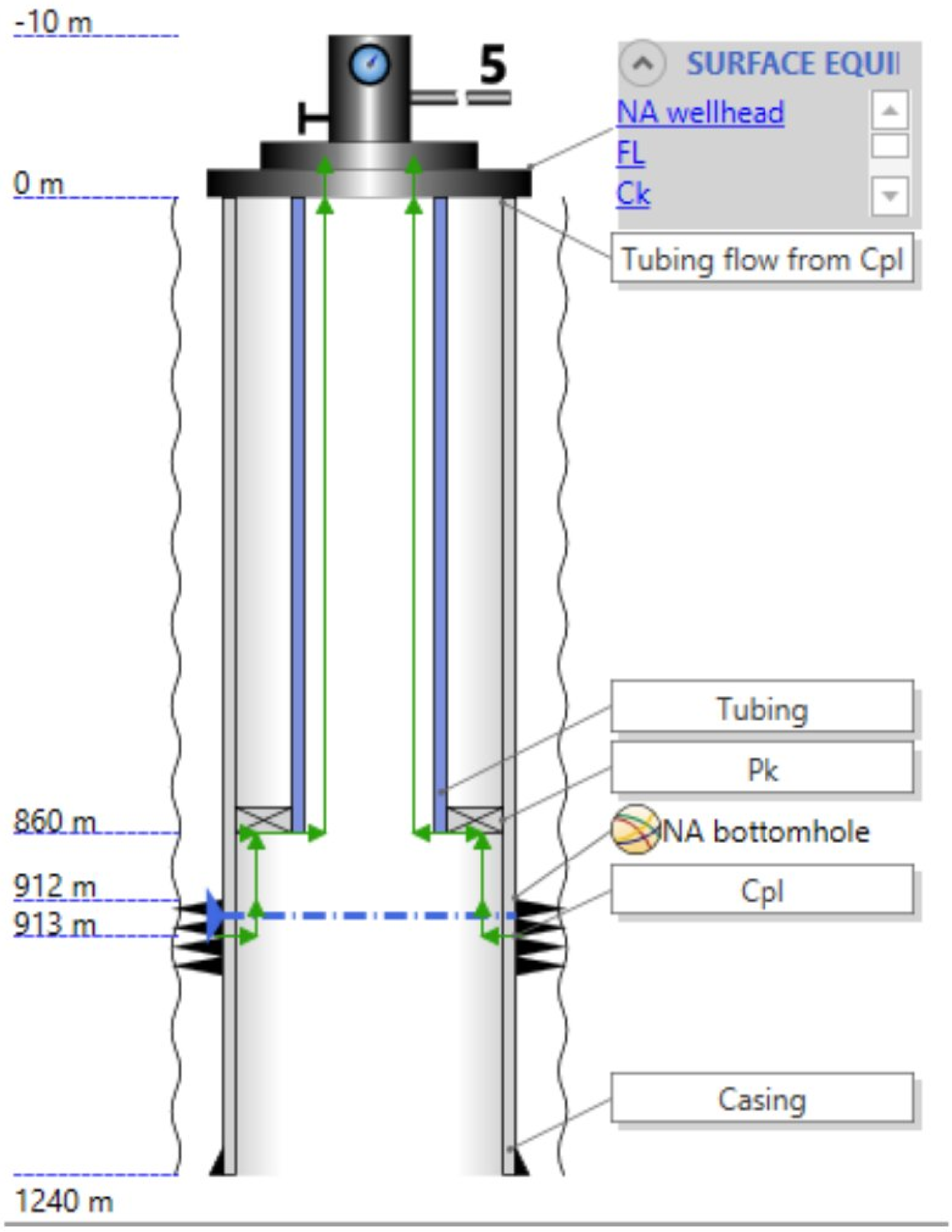

Figure 2 Sketch of well

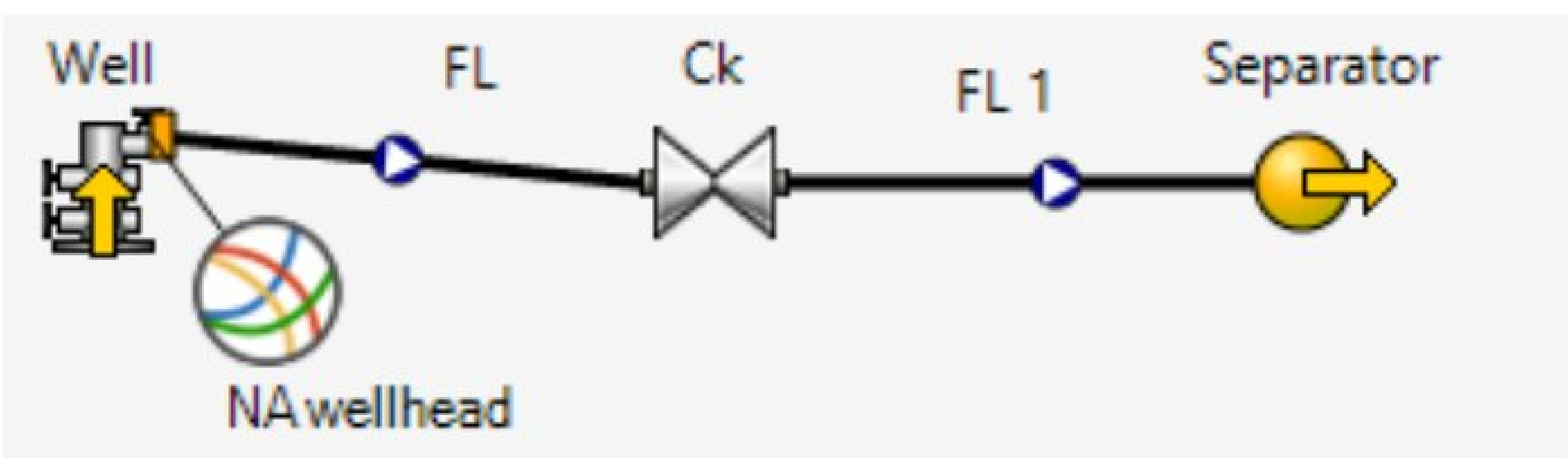

Figure 3 Surface equipment

As the next step in solving the given business case, following the establishment of the wellbore construction and characterization of the fluid, production and pressure were imposed at both nodal points (bottomhole and wellhead NAs) based on available production data and results of hydrodynamic measurements. Subsequently, in the continuation of the scientific paper, the solution at the bottom of the wellbore (Fig. 4) and the solution at the wellhead (Fig. 5) are presented. Vertical Lift Performance (VLP) is described by the Gray (Gray 1974) correlation, while fluid inflow from the reservoir is simulated using the PI method (Craft 1959).

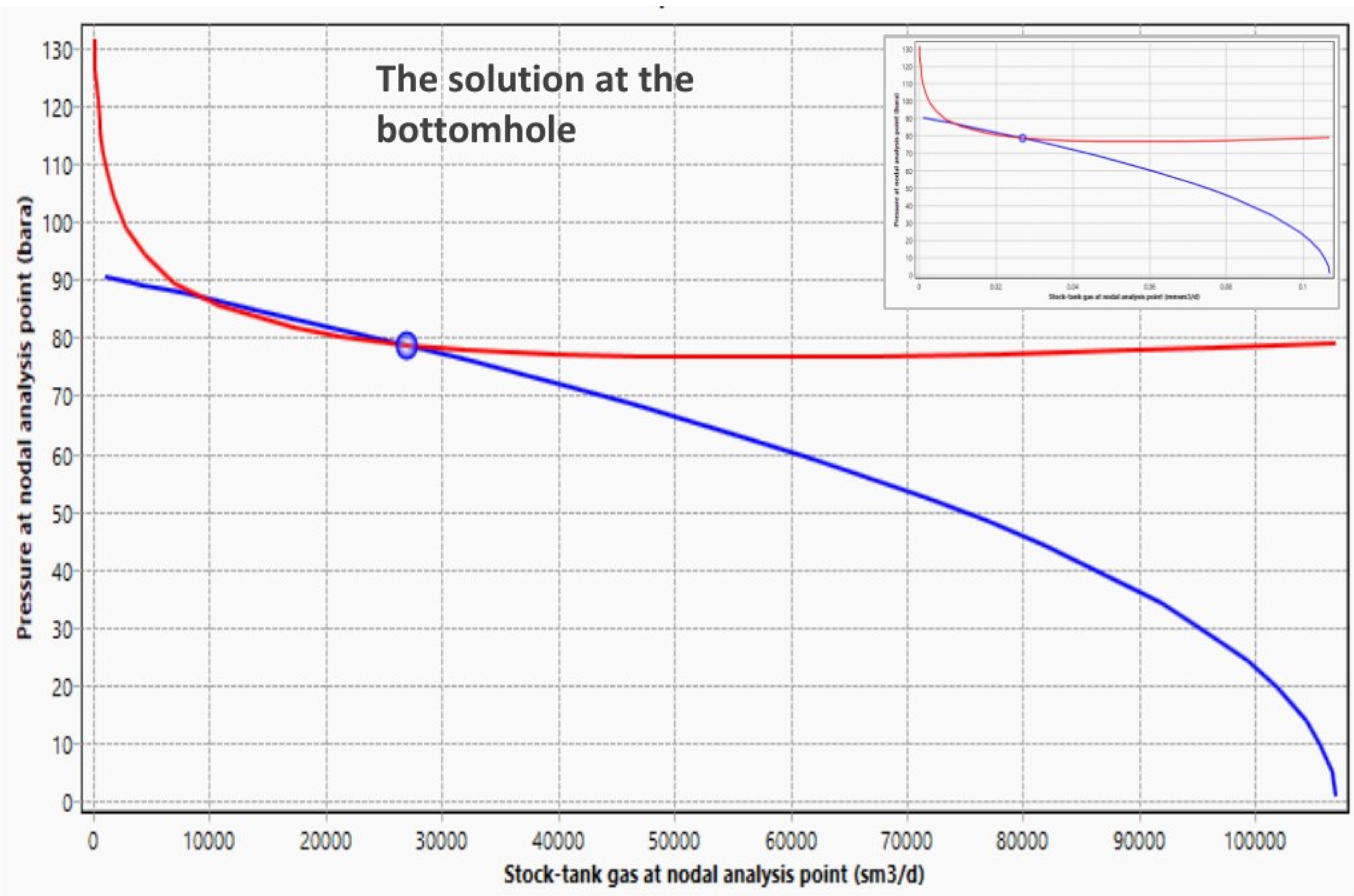

Figure 4 Nodal point at the bottom

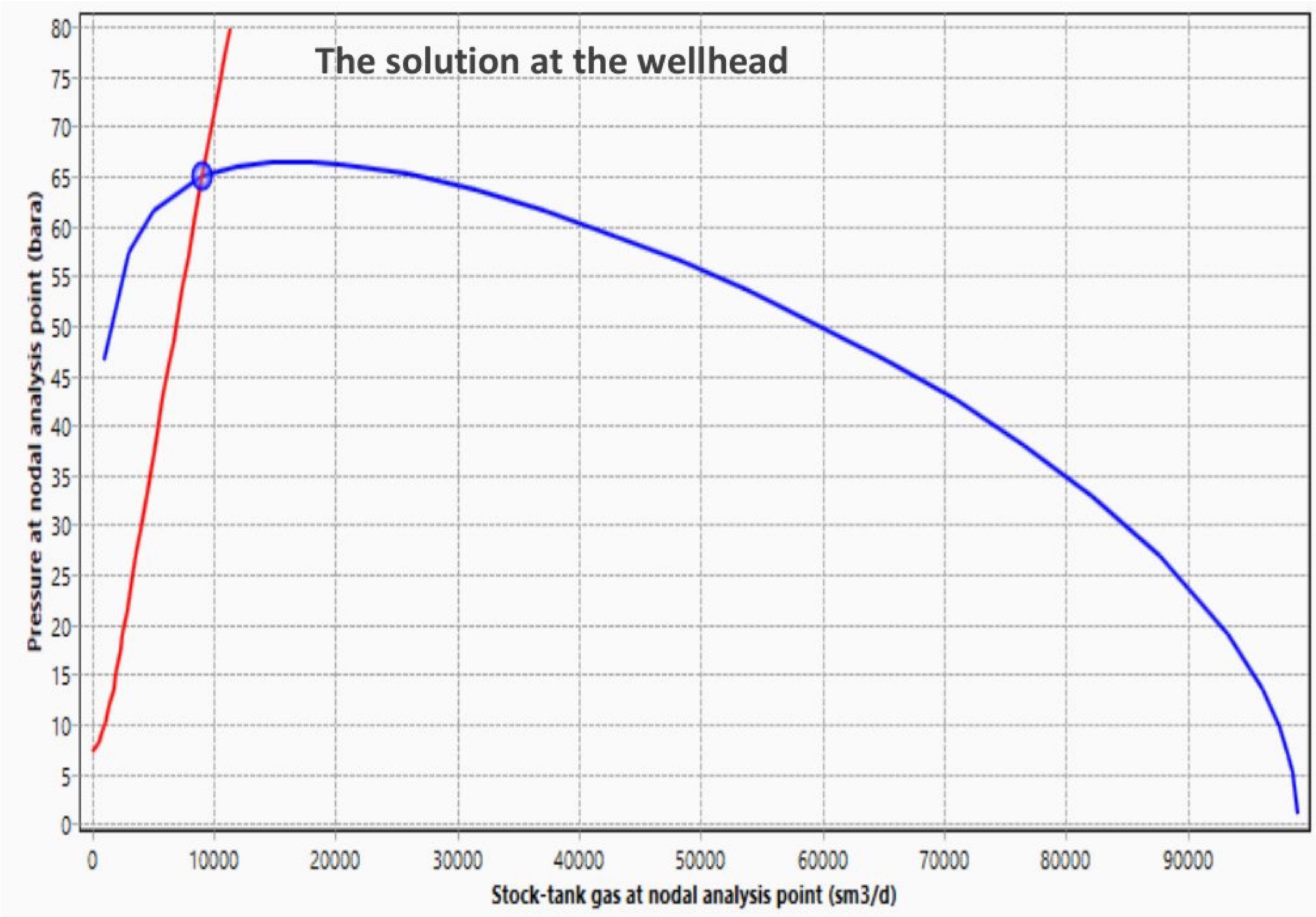

Figure 5 Nodal point at the head

By comparing the results of the baseline model presented in Fig. 4 and Fig. 5 with the input production data from Table 1 (outlined above in the paper), it can be concluded that the model is fitting well, i.e., the well model completely describes the current state of the well, and further analyses can be conducted based on its behavior.

Based on the constructed phase diagram for this well (Fig. 6), an analysis of the hydrate line reveals the potential for hydrate formation within the operational production parameters of pressure and temperature. It is precisely for this reason that we can assert that a thorough analysis of this issue is necessary for this well.

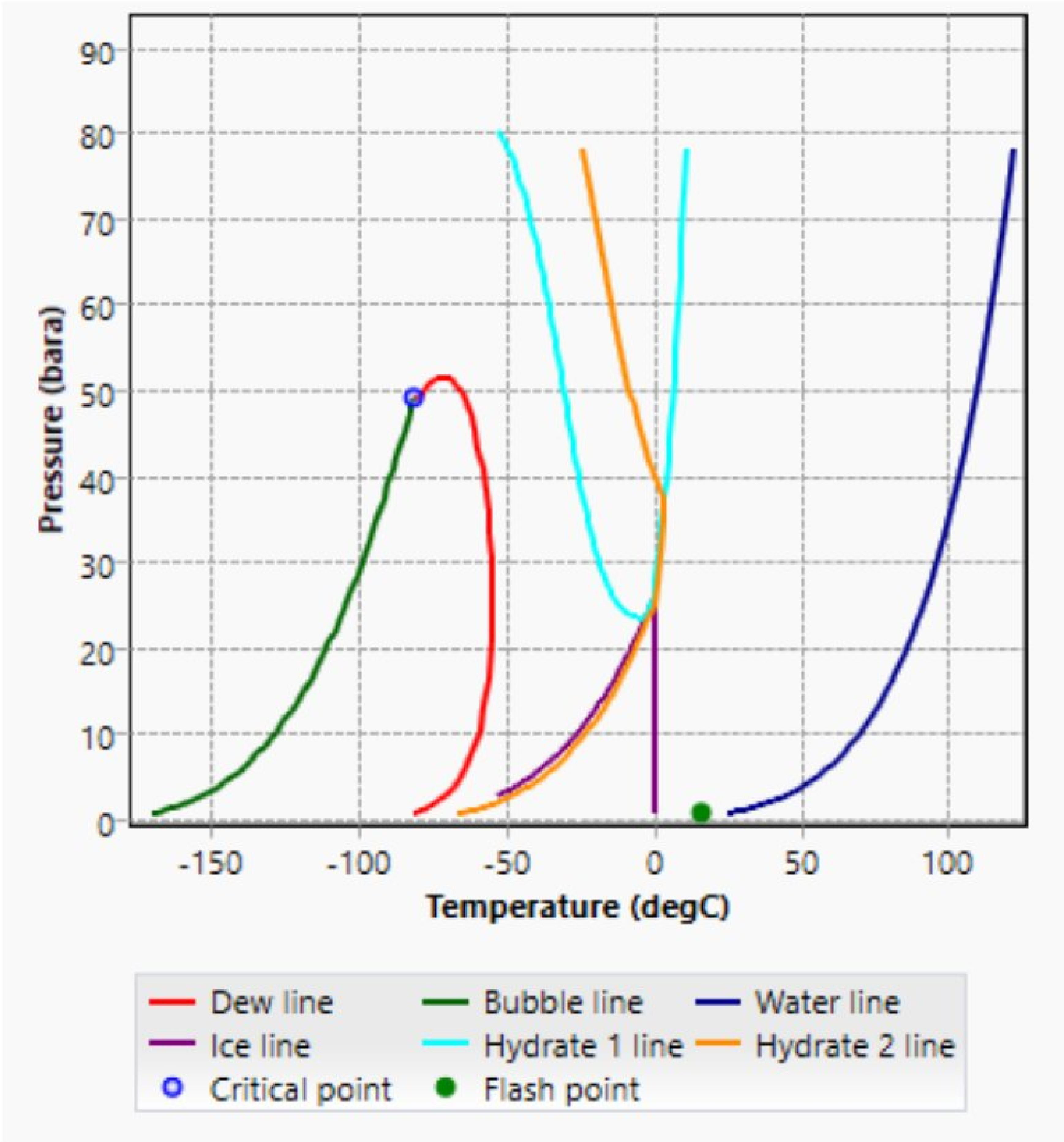

Figure 6 Phase diagram

Hydrate formation risk

In the baseline model, a hydrate formation risk analysis was conducted. Conditions for hydrate formation were tested under ambient temperatures around the wellhead of 5°C, which is the case during winter months in the area where the well is located. Based on the test results (Fig. 7), it is observed that around the wellhead, specifically at the choke (912 m), there is a risk of hydrate formation as the hydrate sub-cooling delta temperature value is above 0°C. From the analysis, it can be concluded that there is no risk in the wellbore column and in the pipeline after the surface choke. In the temperature profile (Fig. 8), it can be seen that in the wellbore, the temperature gradually decreases from the bottom temperature of 60°C to 9°C, which is the temperature of the fluid at the wellhead. At the choke installation point, there is a sudden temperature jump to 18°C, followed by a rapid decrease to -15°C, promoting hydrate formation.

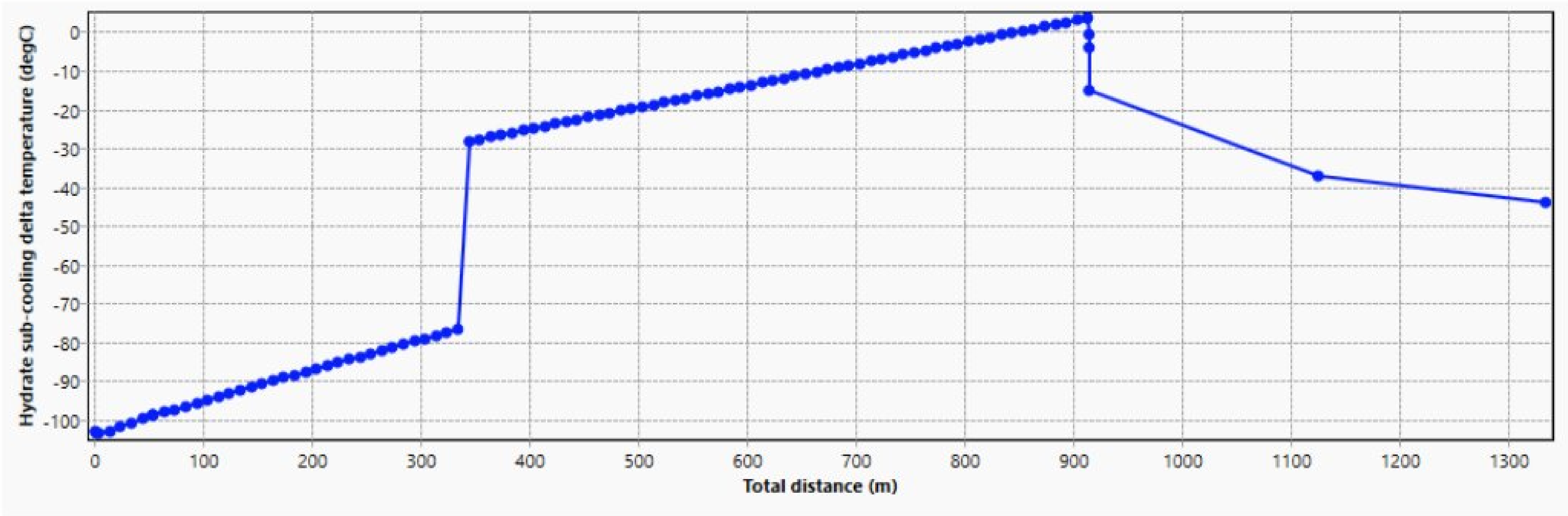

Figure 7 Risk of hydrate formation

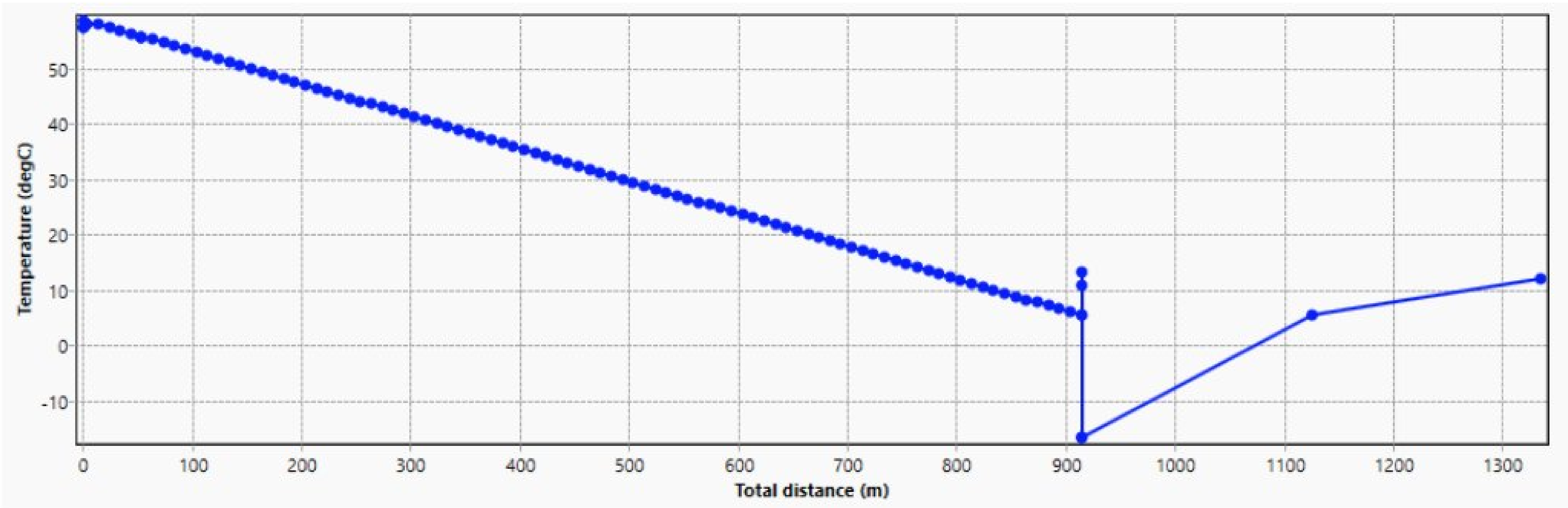

Figure 8 Temperature profile of the wellbore

Installation of a downhole choke

One of the tests conducted in the model to find an optimal solution for the hydrate formation challenge is the installation of a downhole choke. The goal of the performed sensitivity analyses is to determine the minimum installation depth, thus reducing operational costs associated with equipment manipulation.

The first test involved installing the choke at a depth of 50 meters from the wellhead, as illustrated in the diagram below (Fig. 9). Based on the obtained values of hydrate sub-cooling delta temperature, it can be concluded that the chosen depth is insufficient to prevent hydrate formation (Fig. 10).

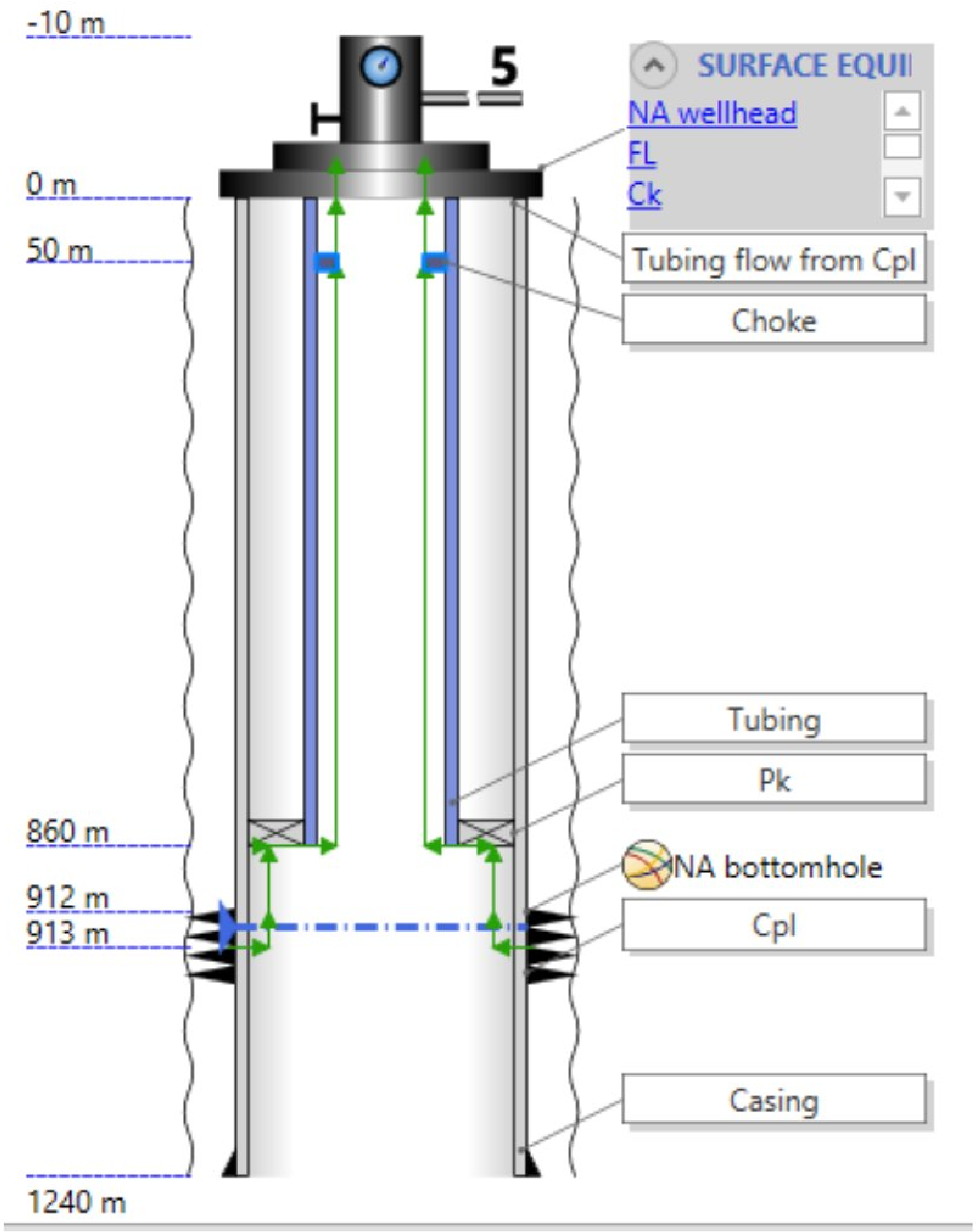

Figure 9 Well construction with a downhole choke at a depth of 50 m

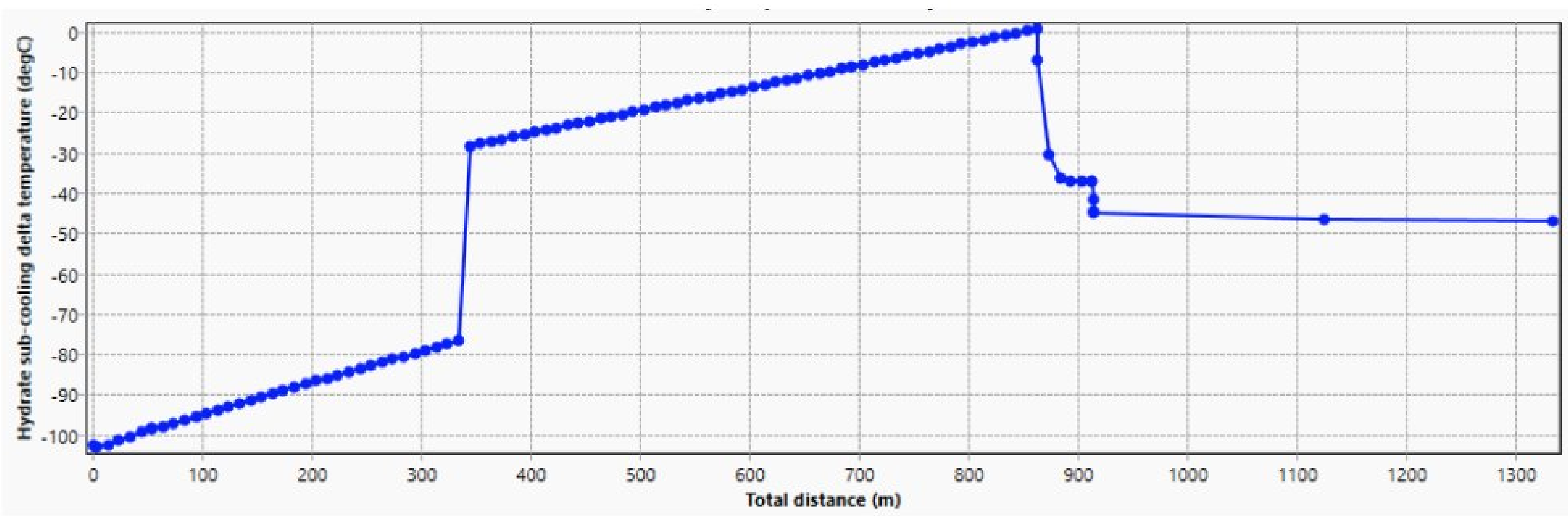

Figure 10 The risk of hydrate formation at a choke installation depth of 50 meters

The next test was conducted by installing the choke at a depth of 100 meters from the wellhead (Fig. 11). A nodal analysis was performed, and based on the results of the hydrate sub-cooling delta temperature (Fig. 12), it was concluded that the installation depth is sufficient to prevent hydrate formation throughout the system: reservoir-wellbore-pipeline-separator, even under winter conditions when the ground temperature around the wellhead is approximately 5°C.

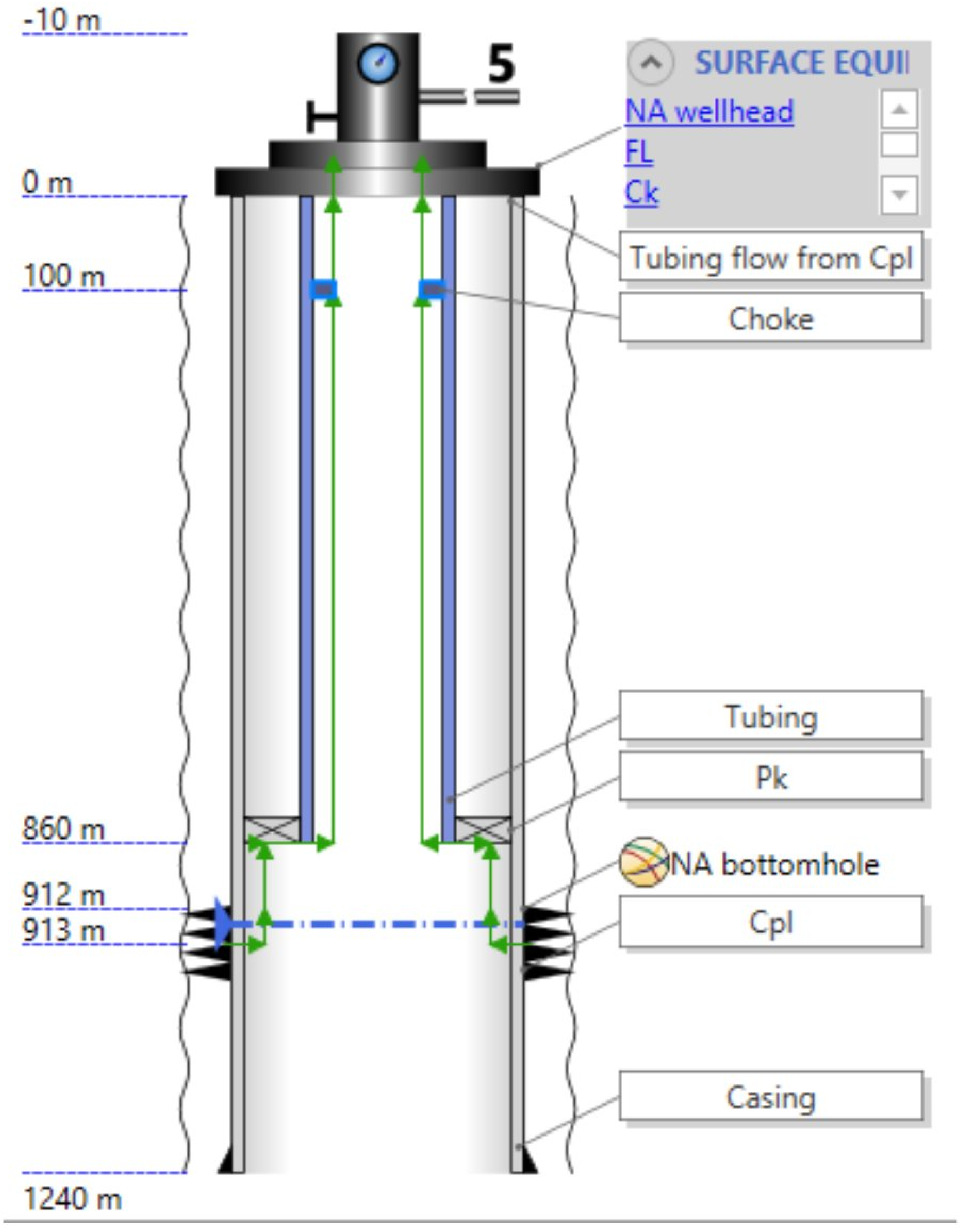

Figure 11 Well construction with a downhole choke at a depth of 100 m

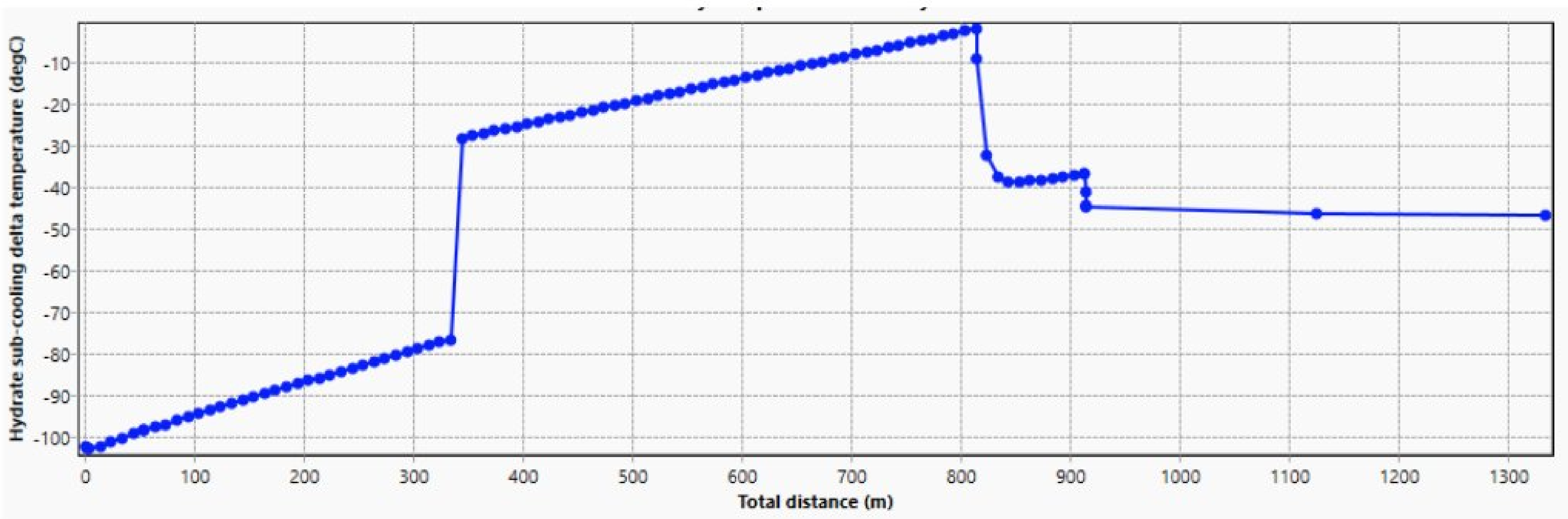

Figure 12 The risk of hydrate formation at a choke installation depth of 100 meters

Methanol dosing

The next method of combat simulated in the model is the continuous dosing of methanol using a dosing pump. This method chemically prevents the formation of hydrate plugs.

The first test involved placing the injection point immediately after the wellhead and before the surface choke located at the location (Fig. 13). A sensitivity analysis of hydrate formation was conducted with different amounts of dosed methanol (Fig. 14). Based on the results, it can be concluded that regardless of the dosed quantity, the problem cannot be solved with the surface injection point alone, as the hydrate sub-cooling delta temperature at the wellhead exceeds 0°C.

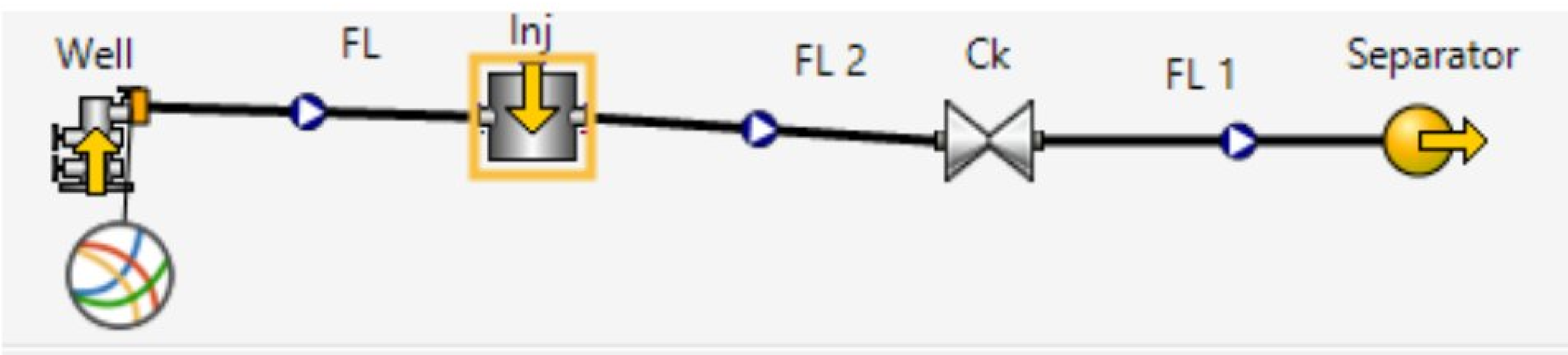

Figure 13 Infrastructure with the methanol injection point in place

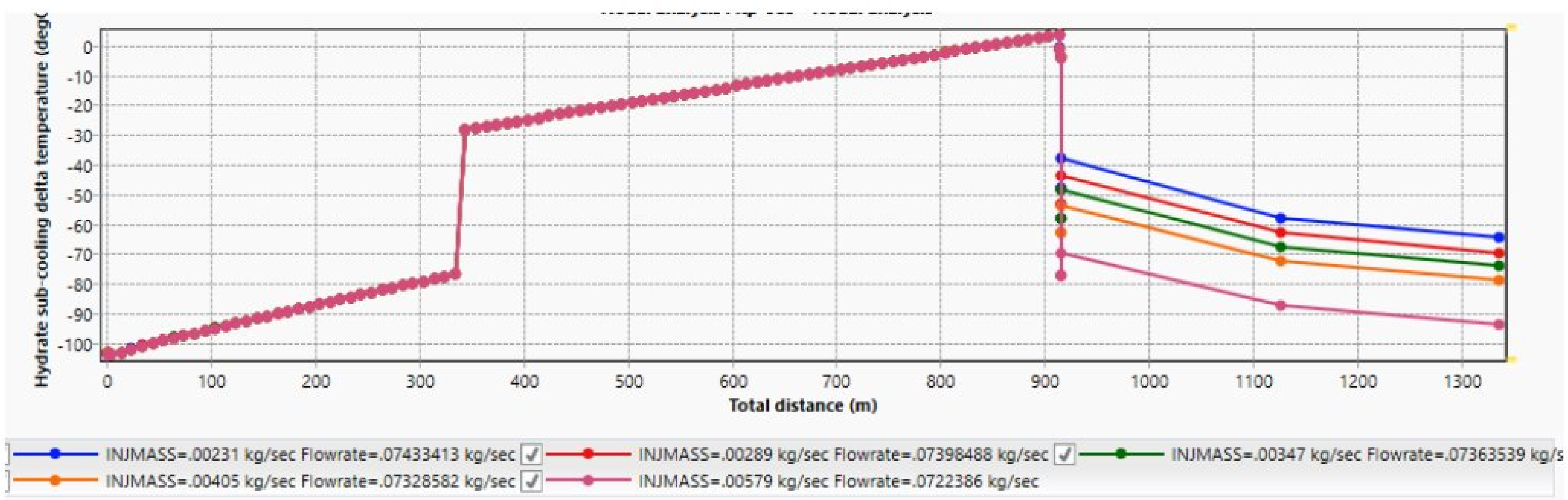

Figure 14 The probability of hydrate formation at different amounts of dosed methanol

In the upcoming test, the dosing point is set 100 m from the wellhead (Fig. 15), achievable through capillary dosing of the inhibitor. Through the analysis of the minimum effective dose, it has been determined that at a dosing rate of 10 kg/d of methanol, the well is at the threshold of hydrate formation. However, at a dosing rate of 30 kg/d, sufficient protection against hydrate formation is ensured (Fig. 16).

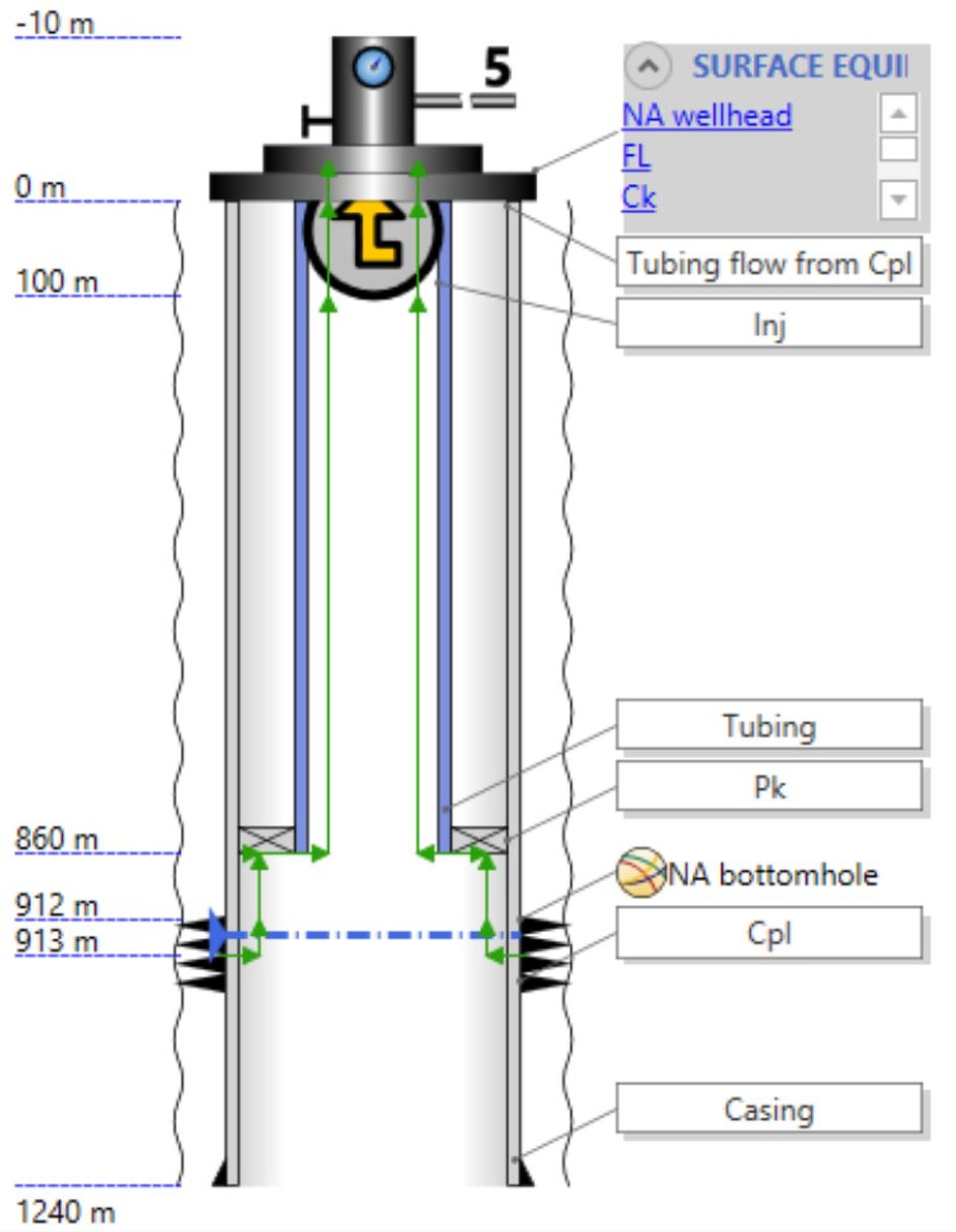

Figure 15 Well construction with the methanol injection point set at 100 m

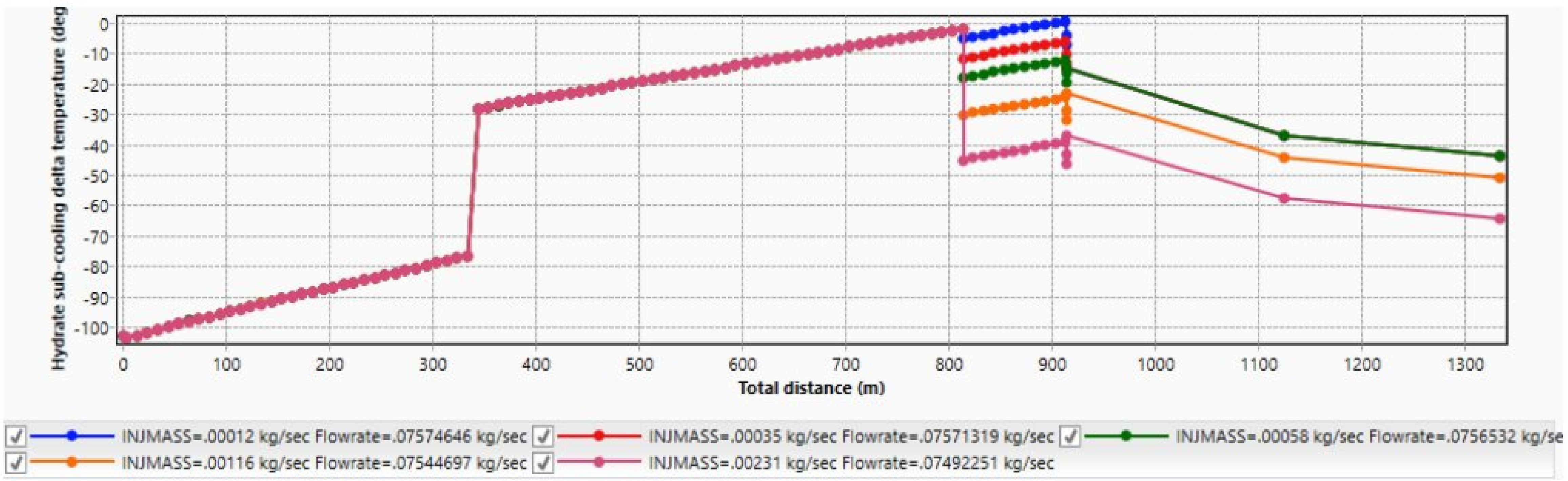

Figure 16 The probability of hydrate formation at different amounts of dosed methanol

At a chemical dosing depth of 200 m (Fig. 17), regardless of the amount of methanol, the necessary protection against paraffin precipitation is ensured (Fig. 18). However, increasing the dosing depth leads to higher operational costs and complicates the equipment installation process.

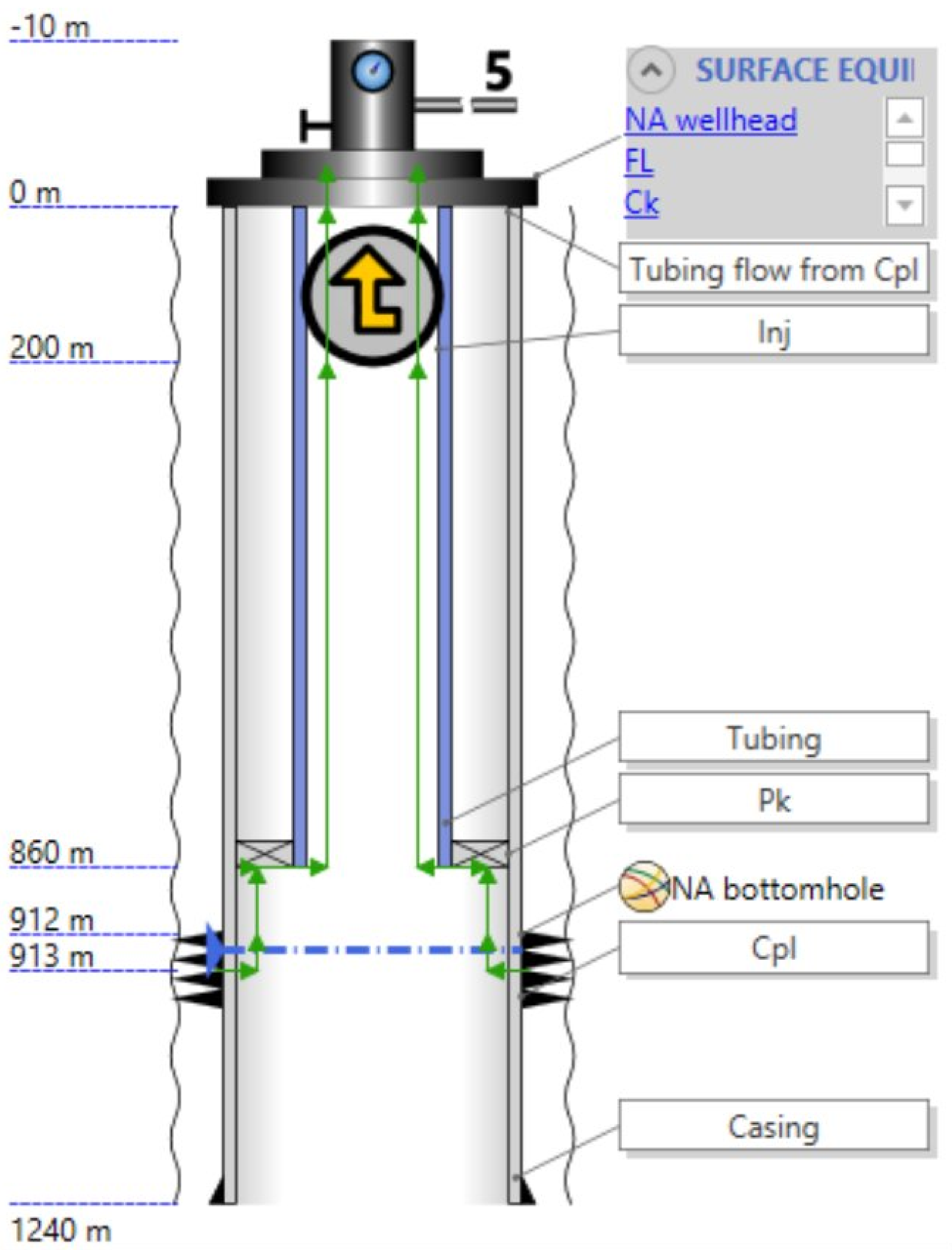

Figure 17 Well construction with the methanol injection point set at 200 m

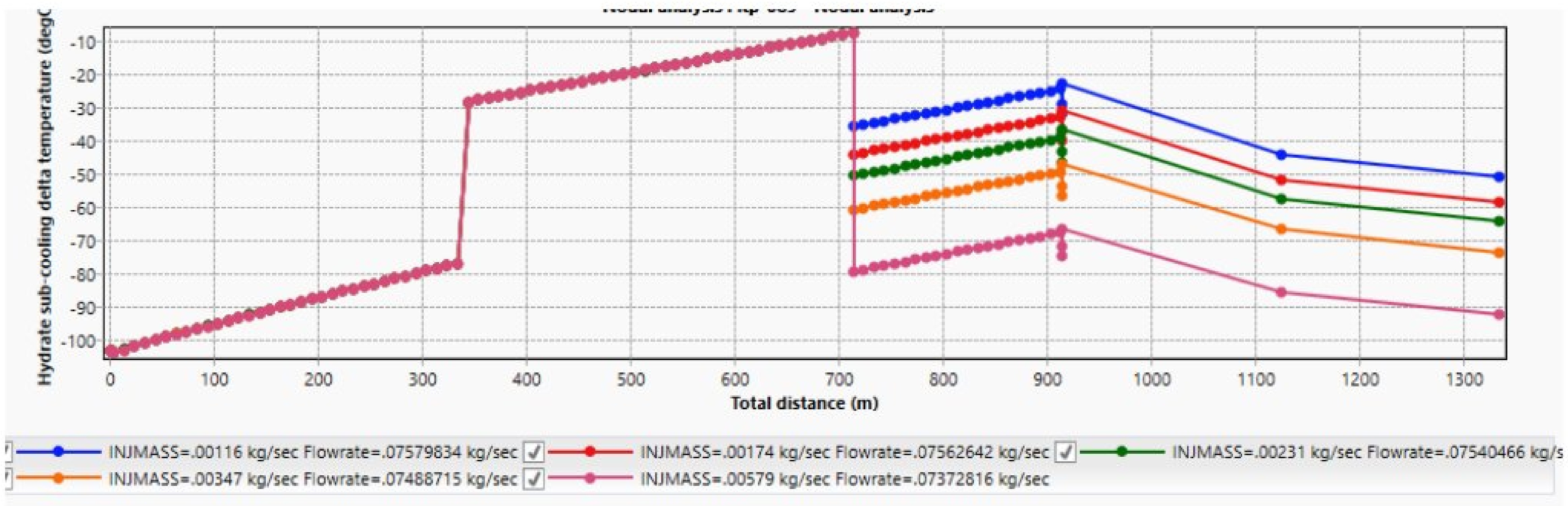

Figure 18 The probability of hydrate formation at different amounts of dosed methanol

Well transfer to a high-pressure separator

One of the methods to combat this is to transfer the well from a low-pressure separator to a high-pressure separator, which has been implemented in this well. During the change in separator pressure from 7 bar to 43 bar, there is a slight pressure increase at the wellhead by several bars, and the production decreases by almost 2000 m3/d. This can be compensated by increasing the choke diameter. The results of nodal analysis during the change in separator pressure are presented below in the paper – the solution at the bottomhole nodal point (Fig. 19) and the solution at the wellhead nodal point (Fig. 20). However, the analysis of the probability of hydrate formation shows that this measure is not sufficient to address the issue in winter months and can only be applied in conditions where the ambient temperature is above 10°C (Fig. 21).

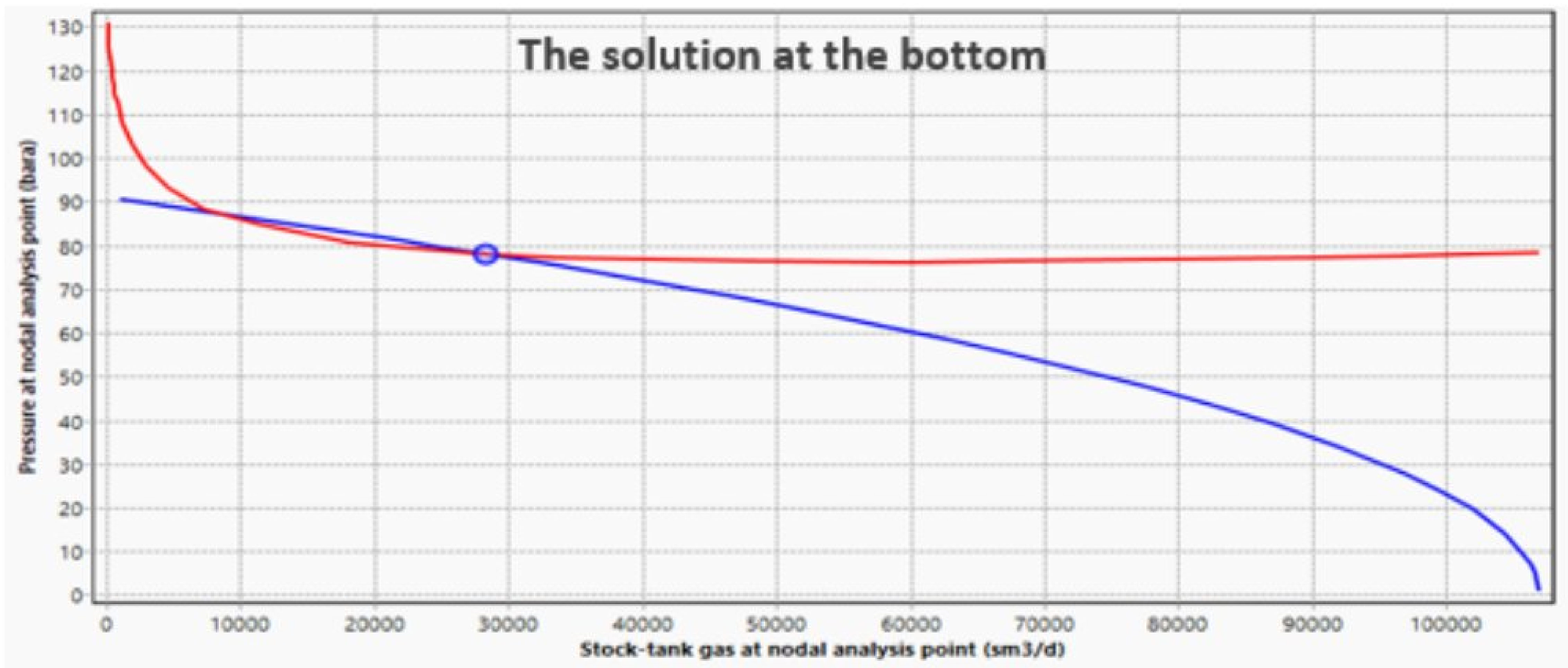

Figure 19 Well model at high pressure translation – nodal point at the bottom

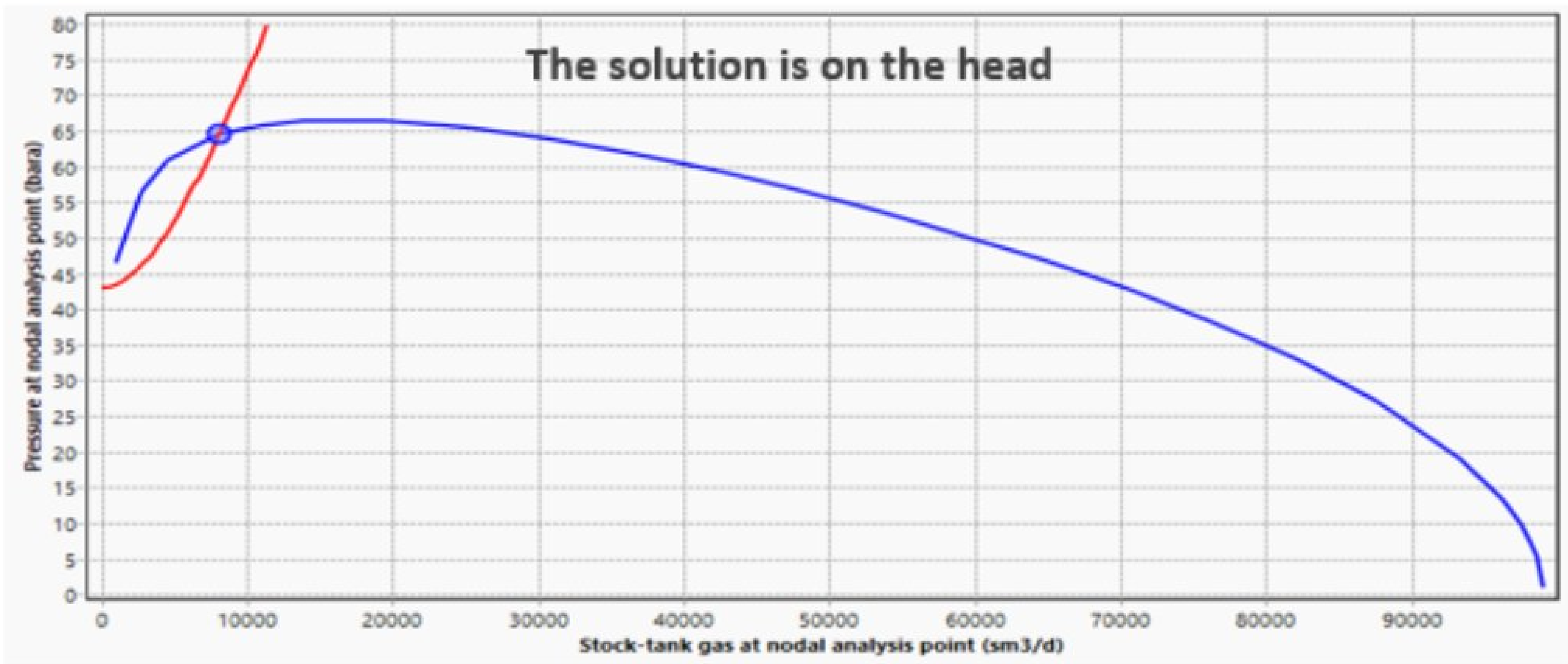

Figure 20 Well model at high pressure translation – nodal point at the wellhead

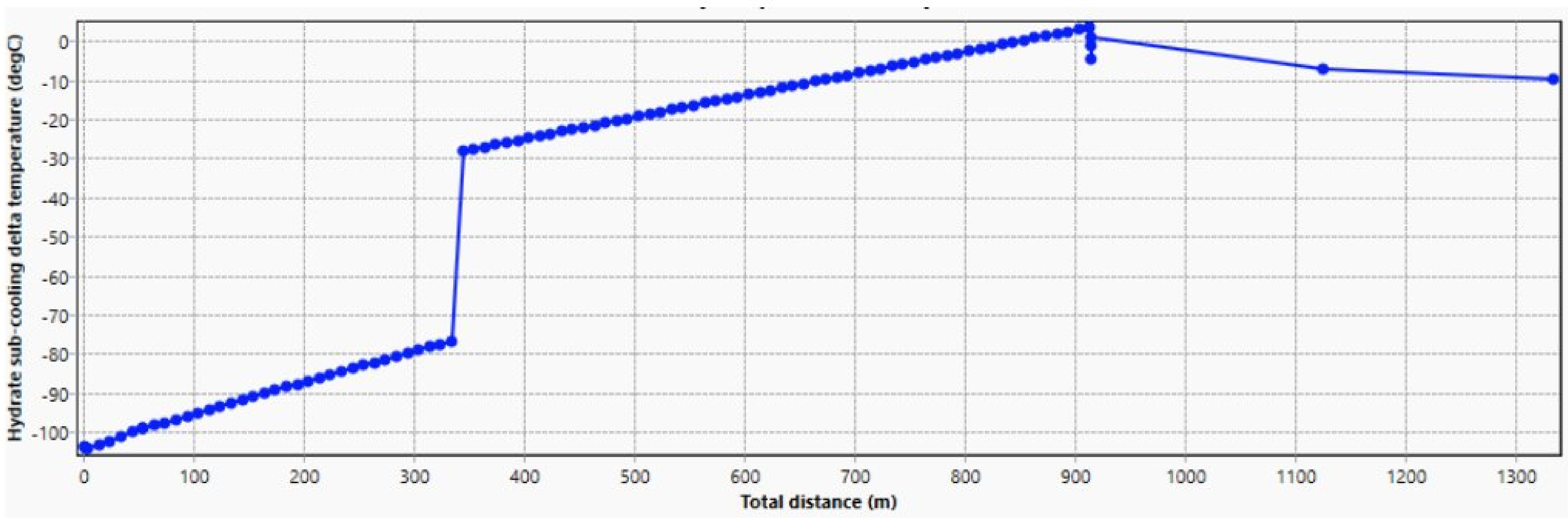

Figure 21 The probability of hydrate formation after transferring the well to a high-pressure separator

5 CONCLUSION

The issue of hydrate formation is a common challenge in the exploitation of gas wells, making it a perpetually relevant subject. While there are several approaches to addressing this problem, it is essential to individually assess each case and each well. Nodal analysis and the development of well modeling software have made it possible to do so. Currently, modeling is an indispensable tool for engineers in defining measures and recommendations for preventing hydrate formation, both in pipelines and tubing wells.

This paper presents a methodological approach to the analysis and resolution of the problem using a specific well as an example. Three methodologies and their effectiveness in the specific case were analyzed – installing a downhole choke, dosing methanol, and transferring the well from a low-pressure separator to a high-pressure separator.

Based on sensitivity analyses conducted on the well model, it was concluded that preventing hydrate formation by installing a downhole choke at a depth of 100 m from the wellhead is possible. Dosing methanol at the surface before the nozzle is not effective in preventing hydrate formation due to a rapid temperature drop at the wellhead. In the case of methanol dosing and combating the problem using this chemical method, it is necessary to dose the chemical at a depth of 100 m through capillary dosing at a rate of 30 kg/d. In this specific case, transferring to a high-pressure separator is not a sufficiently effective method for application in the winter period when the ambient temperature is below 5°C.

Considering all the presented information and the results of all conducted analyses, the author's recommendation is to install a downhole choke at a depth of 100 m, which is economically more viable than capillary methanol dosing. This approach also allows for the prevention of hydrate formation.

It's important to note that during the workover for installing a downhole choke, there are one-time installation costs if a choke seat already exists. If not, workover is required, including installation of both the seat and the choke. On the other hand, with methanol dosing, there are capital investments for dozing pump, workover for the installation of capillary pipes, and ongoing operational costs related to methanol consumption.

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